

A NOVEL APPROACH TO COAL-FIRED POWER GENERATION WITHOUT CO₂ EMISSION

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ABSTRACT

The Department of Energy and Foster Wheeler jointly are studying a novel technique to capture CO₂ by using CO₂ as the working fluid in the power cycle. This CO₂ cycle can be applied to combustion, gasification, or hybrid technology and promises high system efficiency while concentrating CO₂ for 100% sequestration.

In the hybrid cycle application, a mixture of CO₂ recycled from the gas turbine exhaust, and oxygen constitutes the working fluid. Excess oxygen in the gas turbine exhaust is recycled with the CO₂ back to the system, minimizing oxygen usage. The process eliminates the need for CO₂ enriching, absorption, and stripping processes and allows direct collection of CO₂ at the gas turbine compressor discharge pressure or boiler exit. This results in a simpler CO₂ collection process than conventional pre-combustion CO₂ capture systems while providing lower cost and improved efficiency.

In pulverized coal boiler application, coal is combusted utilizing oxygen mixed with recycled flue gas. The furnace is specially adapted to O₂-firing by optimizing the designs of burners and internal surfaces. Flue gas is recycled to maintain acceptable waterwall temperatures. High boiler efficiency is achieved by recovery of most of the flue gas exhaust sensible heat. Boiler size can be drastically reduced due to high combustion temperatures and gaseous radiative emissivity.

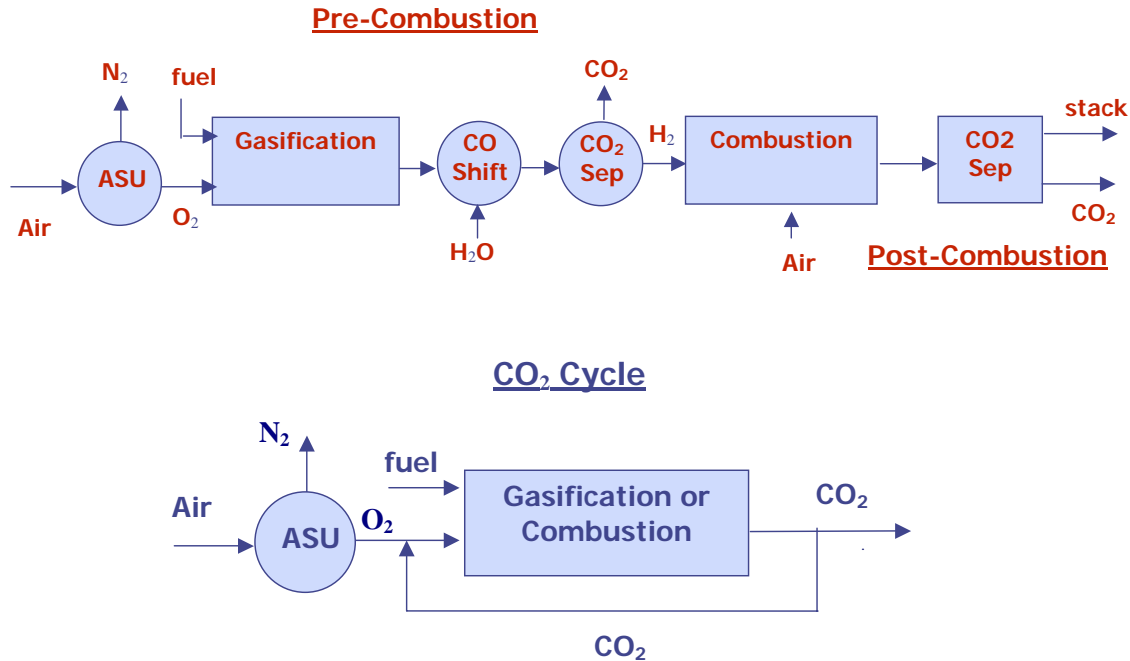
The conceptual design of these plants and their performance, including loss due to CO₂ sequestration, is presented. Comparison with other proposed power plant CO₂ removal techniques is shown. These projects support the DOE research objective of development of concepts for the capture and storage of CO₂.

INTRODUCTION

The linkage between global climatic change and the emission of greenhouse gases such as carbon dioxide (CO₂) is well documented. Coal-fired power plants are some of the largest emitters of CO₂. To assure continued U.S. power generation from its abundant domestic coal resources, new coal combustion technologies for power plants with CO₂ removal and high efficiency must be developed to meet the future emissions standards, especially CO₂ sequestration. Reduction of CO₂ emission from power plants can be obtained by a new concept that has high power generation efficiency and low CO₂ removal cost.

Combustion of fossil fuels in a power plant will inevitably lead to CO₂ emissions. Environmental legislation is currently driving the development of power generation schemes that allow the CO₂ produced to be sequestered. Several possible alternatives exist for the CO₂ removal and sequestration. The simplest method, referred to as post-combustion capture, is merely to scrub the CO₂ from flue gas by chemical absorption. However, this is the most expensive option. One alternative is to apply pre-combustion capture in a pressurized gasification system to separate the CO₂ from a pressurized syngas stream before combustion. This method, where a water-gas shift reaction is first used to maximize the CO₂ partial pressure, allows for a physical absorption which incurs less energy penalty than chemical absorption. Another approach is direct CO₂ removal in a CO₂ cycle, where fuel is combusted using pure O₂ so that the flue gas produced is essentially CO₂. A comparison of CO₂ removal methods is shown in Figure 1.

Figure 1 - CO₂ Removal Methods



A published study [1, 4] has shown that CO₂ removal/sequestration systems applied to the back end of a pulverized coal-fired plant can reduce its efficiency by up to 11 points with a resulting \$30 per ton CO₂ removal cost. For oxygen-blown gasification plants, carbon monoxide can be water-gas shifted to hydrogen and CO₂ upstream of the gas turbine. The concentrated CO₂ is then separated by pre-combustion absorption, and regenerated by stripping or flashing. The resulting CO₂ stream is compressed to a pipeline pressure for sequestration.

There are both direct and indirect power (or efficiency) penalties associated with CO₂ removal. The direct penalty occurs as a result of the increase in auxiliary power requirements of CO₂ separation and compression. The indirect penalty is less obvious and refers to the gross power decrease due to CO₂ enrichment and removal processes. The systems net power and efficiency is reduced due to both direct and indirect penalties.

In the pre-combustion separation technique, the water-gas shift reaction is used to shift CO to CO₂ in order to concentrate the CO₂ in syngas. It has been well documented that this reaction reduces the syngas LHV while releasing its fuel energy as heat. Therefore, more syngas needs to be generated from gasification to compensate for the LHV loss by shifting. The low-grade heat from the shift reaction and syngas cooling before CO₂ absorption contributes to system energy loss. An efficiency loss of 6% with a CO₂ removal cost of \$15 per ton is estimated for such a power plant with a pre-combustion CO₂ removal system [1, 4]. To obtain a high CO conversion for more CO₂ to be removed, a ratio of H₂O/CO > 2 needs to be maintained by steam injection into the syngas. This steam can be extracted from the steam turbine, or generated from syngas cooling. Both ways reduce steam turbine power generation because of less steam flow to the bottoming cycle.

The loss of working fluid is another source of indirect penalty. In the pre-combustion separation technique, working fluid loss is caused by the removal of pressurized CO₂ from the syngas stream and by condensation of excess steam from the water gas shift. The losses of working fluids reduce power generation from the gas turbine because of less flow through the turbine. Indirect penalties can be quite significant and should be minimized to produce the maximum system efficiency.

Foster Wheeler has proposed an advanced CO₂-cycle for gasification and O₂-fired pulverized coal (PC) systems, in which CO₂ is utilized as working fluid for fuel gasification and gas turbine expansion, as well

as for the steam generator. The proposed advanced system eliminates all indirect penalties by using a mixture of CO₂ recycled from the gas turbine exhaust together with oxygen as the working fluid. This facilitates straightforward concentration of CO₂ without enriching and separation processes. It eliminates the need for CO shifting, syngas cooling, absorption, and stripping and allows direct collection of CO₂ from recycled flue gas. It leads to a simpler CO₂ collection process than the conventional oxygen-blown pre-combustion CO₂ capture systems, while providing the advantages of lower cost and lower efficiency loss. Moreover, oxygen usage is minimized by recycling from the gas turbine exhaust most of excess oxygen along with the CO₂ back to the system.

Projects are on-going to evaluate this CO₂-cycle with application to advanced coal gasification combined cycle plants and O₂-fired PC plants, in terms of system efficiency, cost, and reliability. These projects support the DOE research objective of development of concepts for the capture and storage of CO₂.

CO₂ RECYCLING CONCEPT APPLICATION

O₂ PC

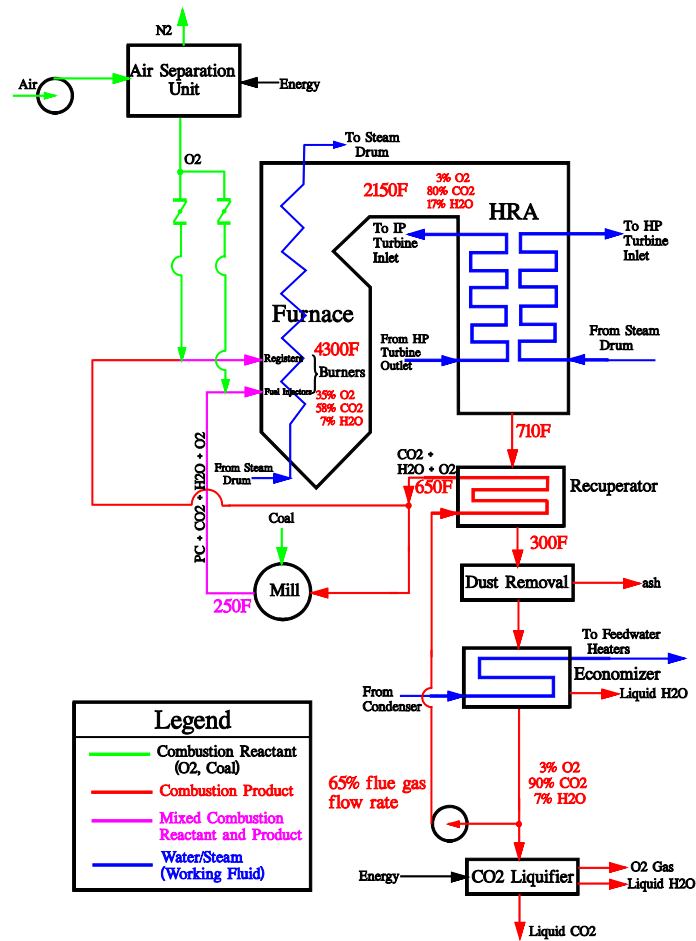
The unique features of the oxygen-based pulverized coal boiler design are shown in Figure 2, which, in application to a subcritical or a supercritical steam generator in a Rankine steam cycle, forms a high efficiency, stackless, near-zero emission power station. The coal is combusted in the furnace or radiant section of the boiler where the oxidizer consists of a mixture of O₂ and recycled flue gas, which contains primarily CO₂ gas. The furnace is specially adapted to O₂-firing by optimizing the designs of burners, ports, internal radiant surfaces, tube materials, and water/steam circuitry. Air is separated into O₂ and N₂ using techniques such as cryogenic air separation or the more efficient membrane-based techniques. Recycling of the flue gas is utilized to control flame temperature in the furnace to maintain acceptable waterwall temperatures and fuel NO_x release. NO_x formation is minimized by advancing NO_x control technologies such as combustion staging and low NO_x burners.

Oxygen is combined with recycled flue gas and pulverized coal from the mill and is introduced into the furnace. In the furnace, the coal and oxidizer produce stable combustion to reach a peak flame temperature of 3500 – 4500°F (depending on the quantity of recycled flue gas) and, after transferring heat to the boiling water within the waterwalls, leaves the furnace at a temperature of 2100 – 2500°F. The flue gas then enters the heat recovery area (HRA) or convective section of the boiler where it transfers heat to steam flowing in the superheater and reheater banks, and leaves at a temperature of 700 – 800°F. Sensible heat energy of the flue gas exiting the HRA is recovered in the gas recuperator, where recycled CO₂ is preheated to a temperature of approximately 650°F, and in the feedwater economizer. Ash removal is accomplished in a dust removal device (such as an electrostatic precipitator) which is located between the recuperator and the economizer. The cold flue gas exits the economizer and contains primarily CO₂ (over 90% by mass) and small amounts of O₂ and H₂O. The cold flue gas is split into two streams: 1) recycled to the furnace through the recuperator (65 – 70% flue gas flow) and 2) condensed and compressed to produce a liquid effluent (30 – 35% flue gas flow). The preheated recycled flue gas is split into primary and secondary streams. The primary stream is sent to the coal pulverizers/mills, where it is used for drying and transport of the pulverized coal, and exits the mill at a temperature 250 – 350°F.

The flue gas effluent stream (mainly CO₂) is compressed to the pipeline pressure of 1200 to 2000 psia using four-stage compression with inter-stage cooling. Residual moisture is removed using a chemical method of active dehydration. Non-CO₂ gases (mostly O₂) are removed from the effluent stream and are recycled back to the system and to reduce air separation unit duty and to recover power.

This liquid CO₂ stream is sequestered in geologic formations (depleted oil and gas reservoirs, unmineable coal seams, saline formations, and shale formations) or in oceans.

Figure 2 – O₂ PC Boiler Schematic



CO₂ Hybrid System

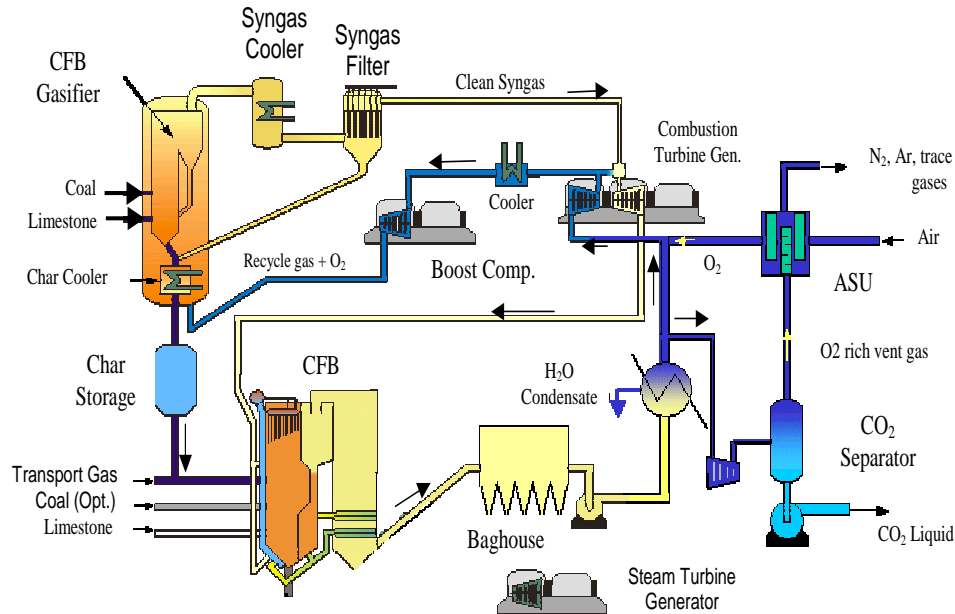
The Hybrid CO₂ Cycle is a simple and efficient method of generating energy while sequestering all of the CO₂ and other pollutants formed in the process. A Schematic of the process, based on a Foster Wheeler's hybrid technology is shown in Figure 3.

The first step of the process is air separation, where oxygen is extracted for use in both the gasification and combustion processes throughout the plant. The oxygen is mixed with recycled flue gas and is routed to the partial gasification module (PGM), the combustion turbine (CT), and the steam generator. In the partial gasification module, oxygen reacts with coal and steam to generate two fuel streams: syngas and char residue. The syngas generated by the PGM is combusted with a mixture of oxygen and recycled CO₂ to drive a gas turbine generator. In the steam generator, char generated in the PGM is burned with the oxygen in the gas turbine exhaust to generate steam for the steam cycle.

Since pure oxygen is used in the combustion process, exhaust flow recirculation is used to control temperature and maintain process velocities. This recirculation occurs in two main ways and provides for the exchange of energy between the topping and bottoming cycles. The gas turbine exhaust, which consists mostly of CO₂, O₂ and H₂O, is sent to the steam generator. This allows the steam generator to recover the considerable sensible heat contained in the GT exhaust and also to utilize its oxygen content for combustion. The CO₂ rich flue gas from the steam generator is recycled to the gas turbine compressor inlet. Once pressurized, the recycle gas goes to the PGM, and also to the GT combustor for temperature control. No additional compressor and associated power is required for O₂ pressurization since the O₂ is part of the working fluid which is mixed with the recycled CO₂ and sent to the gas turbine compressor.

As the final step of the process, a portion of the recycled gas is diverted to a separator where CO_2 is condensed out and pumped away to the sequestration site. This is the only discharge from the plant. There is no stack and no gaseous effluents emitted to the atmosphere. The cycle is completed with zero emissions and 100% of the CO_2 sequestered. The oxygen separated from the CO_2 at the separator is recycled back into the process.

Figure 3 - CO_2 Hybrid Process Flow Diagram



COMPARISON OF CO_2 REMOVAL TECHNOLOGIES

Figure 4 shows the loss of net efficiency when different CO_2 removal processes are added to a power plant. The loss of efficiency is caused by the reduction of power generation and/or the energy loss prior to turbine-generator. As expected, the PC boiler with post-combustion separation has the highest efficiency drop because of the energy intensive nature of the chemical absorption/regeneration. To separate CO_2 from a chemical solvent is much harder than separating O_2 from air through phase separation. Therefore the optimized O_2 -fired PC has a natural advantage over the post-combustion CO_2 separation PC.

The CO_2 -hybrid process has a lower efficiency drop for CO_2 sequestration (compared to the air-blown hybrid cycle (Ref. 2)) than an IGCC with pre-combustion CO_2 removal because the CO_2 -hybrid cycle eliminates indirect losses such as working fluid loss, energy loss due to CO_2 enriching by water-gas shift, and CO_2 separation energy loss. The higher CO_2 separation penalty of the IGCC process can be further illustrated by separating the efficiency loss into two components: 1) due to CO_2 compression and 2) due to CO_2 removal processes, such as steam extraction, CO_2 enrichment and separation, and O_2 /air separation as shown in Figure 4. CO_2 compression and air separation air direct losses, while steam extraction and CO_2 enrichment and separation are indirect losses. Note that with the exception of the CO_2 hybrid, the efficiency loss due to CO_2 separation is higher than the efficiency loss due to CO_2 compression.

Figure 5 shows the power penalty (equivalent to the net efficiency loss of Figure 4) of different CO_2 removal processes. The natural gas combined cycle plant (NGCC) with post-combustion CO_2 capture and the PC boiler with post combustion capture have the largest power penalty because of the low CO_2 concentration in the exhaust gas. By contrast, the O_2 -fired PC shows a low energy penalty for CO_2 removal. The O_2 -fired boiler design has no indirect energy penalty (gross power decrease) and a reduced direct energy penalty (auxiliary power increase) by lower flue gas flow, higher firing temperature and

increased boiler efficiency. Consequently the CO₂ removal penalty for the O₂-fired PC is nearly the same as that of the IGCC with pre-combustion separation.

The CO₂ hybrid cycle has the lowest CO₂ capture power penalty and is only 76% that of the IGCC despite the fact that the CO₂ hybrid cycle has a higher auxiliary power requirement primarily due to the increased power consumption of the air separation unit. However, the gross power loss, which is zero for the CO₂ hybrid cycle, is substantial for the IGCC. For a typical 450 MW IGCC plant, the water gas shift and subsequent CO₂ removal, reduces the syngas flow rate by 25% which reduces the gas turbine power by 22 MW and reduces the steam flow rate which reduces the steam turbine power by 17 MW. To compensate for this loss in gross power, the IGCC must fire more by enlarging the syngas generation system which requires increased capital investment. By using the CO₂ as a working fluid, the CO₂-hybrid cycle eliminates all indirect penalties and does not require any increase in the syngas generation system.

Figure 4 – CO₂ Removal Efficiency Penalty

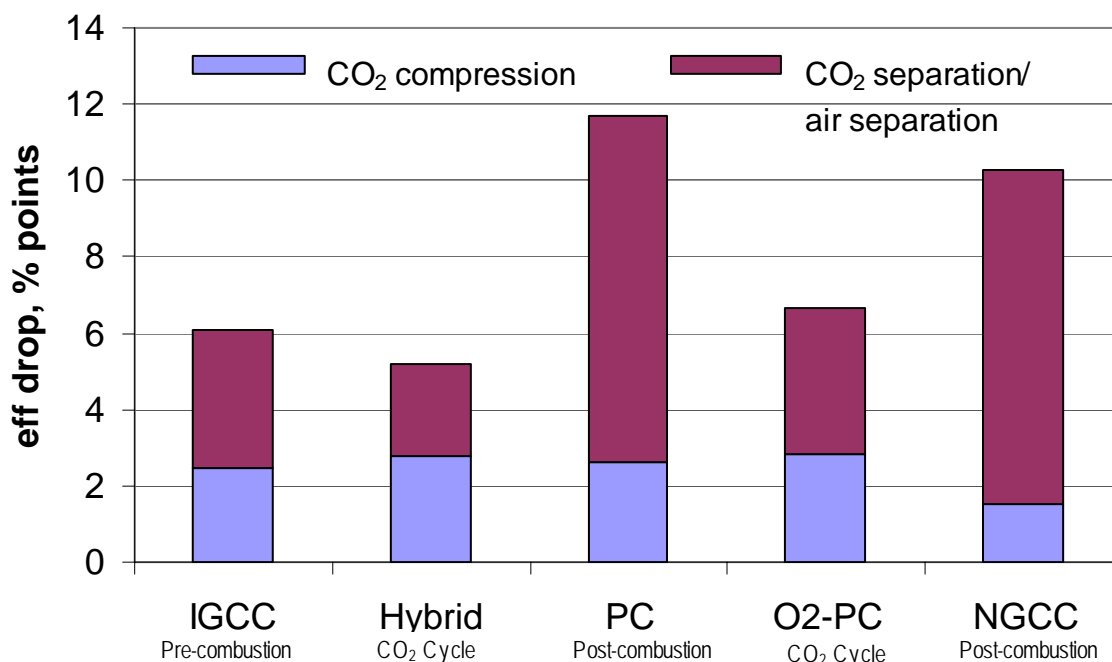


Figure 5 – CO₂ Removal Energy Penalty

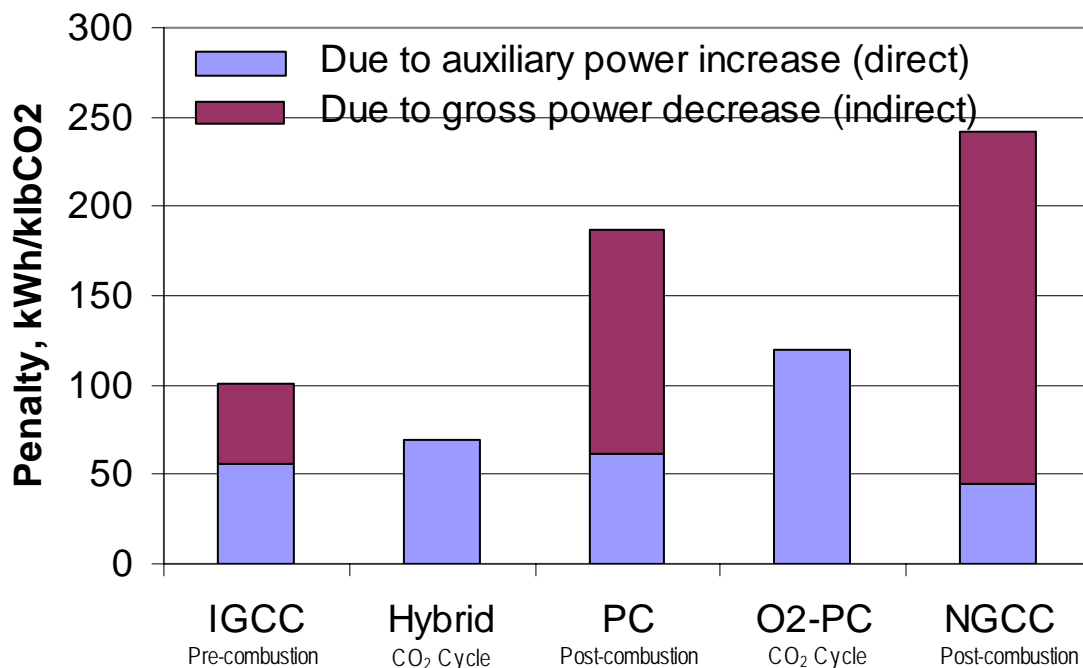


Figure 6 shows the CO₂ power removal penalty for the CO₂ cycle versus other CO₂ removal technologies at a constant heat input of 1400 MWth. Note that the net efficiency of 30.0% listed for the O₂-PC is for a subcritical unit with a 1000°F superheat/reheat temperature; it is expected that this efficiency will increase to 33.5% for a supercritical unit with a 1100°F superheat/reheat temperature.

Figure 6 – Net Efficiency and CO₂ Removal Penalty [1, 3]

	Units	IGCC Pre-Comb	Hybrid CO ₂ Cycle	PC Post-Comb Super Crit	O ₂ -PC CO ₂ Cycle Sub Crit	NGCC Post-Comb
Heat input	MWth	1440	1440	1440	1440	1440
O ₂ feed	klb/hr	373.3	875.7	0	877.6	0
CO ₂ removal	klb/hr	839.4	960.8	897.0	978.7	519.8
CO ₂ removal	%	90	100	90	100	90
Power						
GT	MW	374.5	226.9	N/A	N/A	474.2
ST	MW	191.3	476.1	507.9	605.1	169.9
Total	MW	576.8	703.0	507.9	605.1	632.8
Auxiliary	MW	152.2	172.3	91.8	172.9	37.4
Net	MW	424.8	530.7	329.3	432.4	568.2
Net efficiency	%	29.5	36.8	28.9	30.0	39.5
CO ₂ Removal Penalty						
Aux power increase	MW	46.6	73.8	55.1	117.7	23.2
Gross power decrease	MW	38.1	0.0	112.2	0.0	102.6
Total	MW	84.7	73.8	167.3	117.7	125.8
Total per klbCO ₂	kWh/klbCO ₂	100.9	76.8	186.5	120.2	242.0

CURRENT DOE PROJECTS

O₂-PC

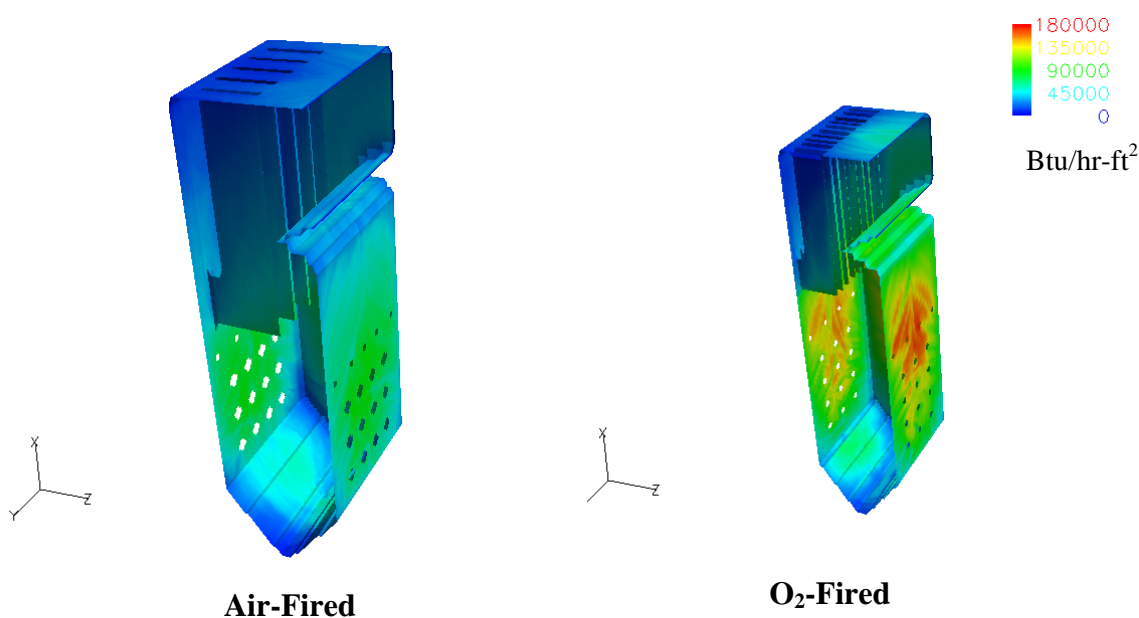
Foster Wheeler, in a cooperative agreement with DOE (DE-FC26-03NT41736), is currently conducting a conceptual design of an oxygen-based pulverized coal boiler power plant. The reference plant applied is a subcritical pressure, natural circulation boiler firing high-volatile bituminous coal generating 460 MWe. A system design and analysis was performed to optimize the PC boiler plant operating parameters to minimize the overall power plant heat rate and to determine the required performance characteristics of plant components. The flow rate of the recycled flue gas was optimized to maximize system efficiency while controlling the flame temperature inside the PC-fired boiler to minimize NO_x formation, minimize ash slagging in the furnace combustion zone, and avoid the application of costly water wall materials. Based on the results of this system optimization, the “cost” of CO₂ capture is a reduction in system net efficiency of 6.3% points (Figure 4) and an energy consumption of 120 kWh/klbCO₂ (Figure 5). This is substantially better than proposed capture techniques in natural gas combined cycles and post PC capture and is comparable to the proposed techniques in integrated gas combined cycle (IGCC) plants.

Detailed design and analysis of key equipment including the burners and furnace is being performed. Because the high oxygen composition of the fuel oxidizer, the O₂-PC burners will be substantially different than standard air-fired burners. Consequently a 3-D CFD modeling of the burner system is being

conducted to ensure stable ignition, provide safe operation, and minimize pollutant formation. A 3-D CFD simulation of the furnace is also in progress to determine required heat transfer surface, required waterwall materials, and amount of pollutant formation. Figure 7 compares the CFD results for wall heat flux in the furnace of the air-fired and O₂-fired furnaces. The average wall heat flux of the oxygen-fired furnace is approximately twice that of the air-fired furnace due to substantially higher CO₂ concentration (75% versus 14%) and a significantly higher flame temperature (3900°F vs. 3400°F). Consequently, the required surface area of the oxygen-fired furnace is only approximately 50% of the air-fired furnace as shown in Figure 7, which shows the two furnaces to scale.

A budgetary estimate of capital and operating costs will be developed for the oxygen-fired power plant as well as for an equivalent conventional pulverized coal-fired power plant.

Figure 7 – Wall Heat Flux and Relative Size of Air-Fired PC and O₂-Fired PC



CO₂ Hybrid

Under United States Department of Energy (DOE) Contract (DE-FC26-02NT41621), research is being conducted to develop a conceptual design and determine the performance characteristics of the CO₂ hybrid system described above.

The CO₂-hybrid cycle conceptual design is based on Foster Wheeler's air blown GFBCC (gasification fluid bed combined cycle) plant [2], which is also used as a reference plant in determining the efficiency drop and energy costs for CO₂ removal.

The objective of this work is to investigate the feasibility of this concept and to determine the technical issues that need to be resolved for commercialization. If successful, this technology could form the basis of a coal-fired power plant with zero emissions and the best CO₂ removal efficiency ever conceived.

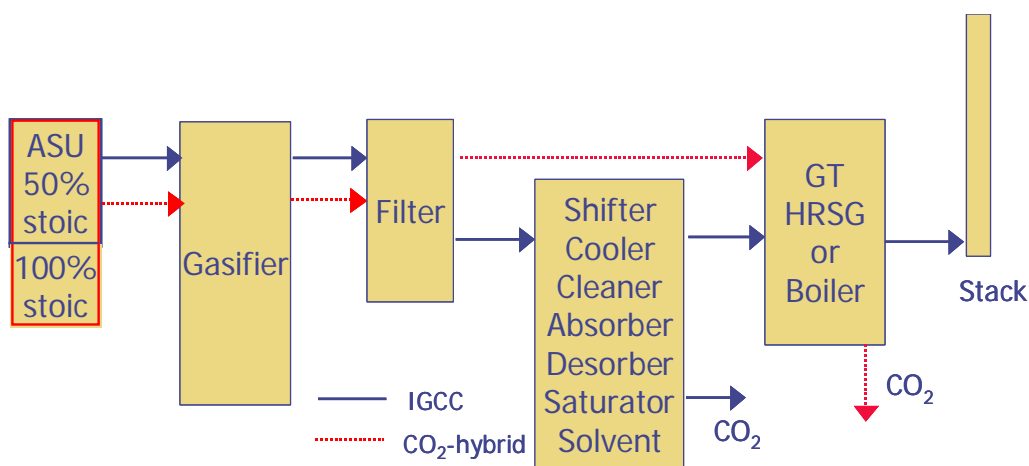
System optimization studies and thermodynamic cycle analyses have been completed, as well as the design of the gasifier and the circulating fluid bed (CFB) boiler. Capital cost calculations and economic analyses are now being performed. As pointed out earlier in the paper, progress to-date has shown that the CO₂-hybrid cycle can sequester CO₂ with greater efficiency than other leading sequestration concepts, including IGCC with pre-combustion CO₂ separation. In addition, the CO₂-hybrid cycle presents a simpler configuration with fewer components. This is illustrated in Figure 8, which shows comparison of

IGCC plant equipment with pre-combustion CO₂ removal to the CO₂ hybrid plant. Compared to the CO₂ hybrid plant, the IGCC plant requires the following additional processes:

- Steam extraction/generation for water gas shift
- Water gas shift to enrich CO₂ content
- Syngas cleanup
- Syngas cooling before CO₂ absorption
- Cooling water support
- CO₂ absorption
- CO₂ desorption
- Syngas saturation

All of the above processes require equipment operating under pressure in a syngas environment. By contrast, the equipment required to convert the same IGCC plant to a CO₂-recycle configuration is relatively simple. One needs only to enlarge the ASU to provide 100% stoichiometric O₂ as opposed to 40-50% stoichiometric O₂.

Figure 8 – Comparison of IGCC and CO₂ Hybrid CO₂ Removal Process



TECHNICAL ISSUES

Co-Disposal of Trace Contaminants

The effluent CO₂ stream of the CO₂ cycle plants contains trace contaminants such as SO_x and NO_x. The ecological impact of these trace contaminants in the selected sequestration sinks requires further investigation. The main categories of CO₂ sequestration sinks are storage in terrestrial ecosystems, geologic formations and in oceans. The potential interaction between the sequestered CO₂ and the environment for each storage method needs to be studied to determine the level of contaminant which can be tolerated in the CO₂ stream.

Advanced O₂ Separation Techniques

Currently in development are several new oxygen separation techniques such as membrane separation and pressure swing adsorption (PSA), which have the potential to substantially reduce the power consumption of the ASU. Further investigation is merited to integrate these new techniques into the CO₂ cycle to determine the improvement in cycle efficiency and the reduction in CO₂ removal cost.

Gas Turbine Availability

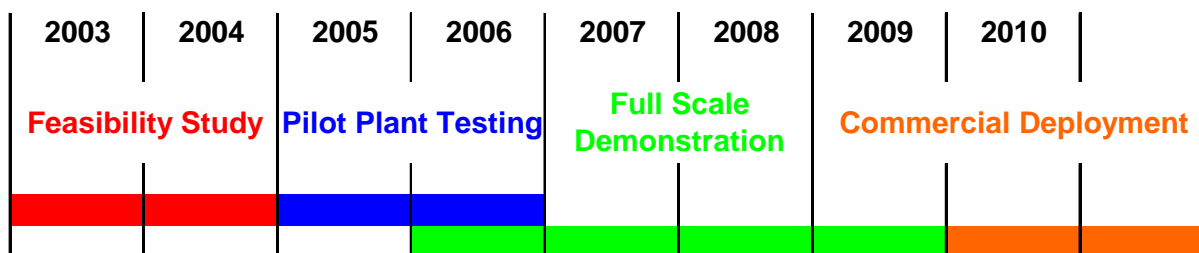
The CO₂ hybrid cycle uses oxygen to burn syngas at the gas turbine combustor. Therefore the turbine inlet gases are composed mainly of CO₂ and some water vapor from the gasification process. The

expansion behavior of CO₂ differs from that of air in that a given pressure ratio across the turbine creates smaller temperature drop for CO₂-rich gas than for N₂-rich gas. In order to maintain a high GT firing temperature and also limit the GT exhaust temperature to 1100°F or lower, the GT inlet pressure must dramatically rise. Using a lower, more typical, compression ratio results in the elevation of the gas turbine exhaust temperature to structurally unacceptable levels. This elevated inlet pressure requirement, as well as other properties of CO₂ as a compressible working fluid, necessitate the use of a non-standard gas turbine design. More work is needed in this area to develop CO₂ gas turbines or to adapt currently available steam turbine derivative expanders.

COMMERCIAL DEMONSTRATION

A crucial step in the commercialization pathway is pilot plant testing and validation of the CO₂ cycle. Depending on the technology issues involved, a pilot scale plant may be anywhere between 1/100th to 1/20th scale of the actual commercial unit. Following successful pilot scale testing would be a large-scale demonstration plant operation. This demonstration would constitute the final step of the commercialization process and would prove readiness for commercial deployment. A potential timeline for either the hybrid plant or the PC boiler plant commercialization is presented in Figure 9.

Figure 9 – CO₂ Cycle Commercial Timeline



CLOSING REMARKS

The CO₂ cycle allows for efficient and economic utilization of our abundant supply of inexpensive coal while addressing the global warming concern associated with power plant CO₂ emissions. This concept, which can be applied to virtually any combustion or gasification technology, holds several unique benefits. The CO₂ cycle power plant completely removes all CO₂ generated in the combustion process and generates zero ambient air pollutants. It avoids costly CO₂ separation processes, which are limited by equilibrium to only 90% CO₂ removal efficiency. Of the CO₂ sequestration-ready technologies, the CO₂ cycle is the simplest, requires the least modification of existing proven designs, and requires no special chemicals for CO₂ separation. Furthermore, the cost-effectiveness of the CO₂ cycle will benefit from several currently promising advanced O₂ separation techniques such as membrane separation. Boiler efficiencies of near 95% can be achieved by recovery of virtually all of the flue gas exhaust sensible heat. Furthermore, a wider range of fuels can be burned due to the high oxygen content of the combustion gas.

When applied to gasification plants, the CO₂ cycle eliminates the extensive equipment and energy losses associated with the water gas shift and CO₂ separation processes. When applied to pulverized coal combustion plants, the CO₂ cycle creates a high efficiency cost-effective design by drastically reducing boiler size due to high radiative properties of O₂-combustion and specifically tailoring boiler material selection, furnace layout, and water/steam circuitry.

ACKNOWLEDGEMENT

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